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Gas-fired power in the UK: Bridging supply gaps and implications of domestic shale gas exploitation for UK climate change targets

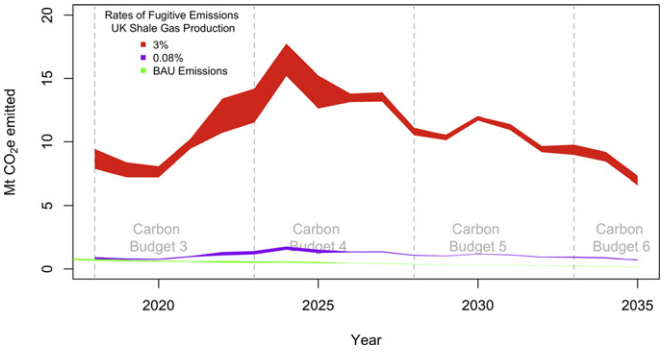
Jeremy K. Turk [a,*], David S. Reay [a], R. Stuart Haszeldine [a,b]

[a] School of GeoSciences, The University of Edinburgh, Edinburgh EH8 9XP, United Kingdom
[b] Scottish Carbon Capture & Storage, High School Yards, The University of Edinburgh, EH1 1LZ, United Kingdom

HIGHLIGHTS

- UK domestic natural gas supply will decline −5% yr^{-1} after 2020.
- UK will need natural gas imports or domestic shale gas to meet supply gaps.
- Domestic shale gas industry will increase overshoot on carbon budgets.
- Grid emissions intensity targets can be met regardless of gas supply origin.

GRAPHICAL ABSTRACT



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ABSTRACT

There is a projected shortcoming in the fourth carbon budget of 7.5%. This shortfall may be increased if the UK pursues a domestic shale gas industry to offset projected decreases in traditional gas supply. Here we estimate that, if the project domestic gas supply gap for power generation were to be met by UK shale gas with low fugitive emissions (0.08%), an additional 20.4 Mt CO_2e[1] would need to be accommodated during carbon budget periods 3–6. We find that a modest fugitive emissions rate (1%) for UK shale gas would increase global emissions compared to importing an equal quantity of Qatari liquefied natural gas. Additionally, we estimate that natural gas electricity generation would emit 420–466 Mt CO_2e (460 central estimate) during the same time period within the traded EU emissions cap. We conclude that domestic shale gas production with even a modest 1% fugitive emissions rate would risk exceedance of UK carbon budgets. We also highlight that, under the current production-based greenhouse gas accounting system, the UK is incentivized to import natural gas rather than produce it domestically.

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1. Introduction

The United Kingdom (UK) is legally bound by 'The Climate Change Act' to reduce greenhouse gas (GHG) emissions by 2050 to 80% below a 1990 baseline (UK Parliament, 2004). The Climate Change Act also empowers an independent body, The Committee on Climate Change (CCC), to advise the Government on progress towards the 2050 goal. The CCC recommends reduction targets in 5-year budget periods. The UK met its first carbon budget (CB1: 2008–2012) of 3018 Mt CO_2e, and is likely to meet the second and third carbon budgets, covering the years 2013–2022 (DECC, 2014a, 2015a). However, the Department for Energy and Climate Change (DECC - now the Department for Business, Energy,

* Corresponding author.
E-mail address: jeremy.turk@ed.ac.uk (J.K. Turk).
[1] Megatonne carbon dioxide equivalent (Mt CO_2e).

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and Industrial Strategy - BEIS) suggests that the UK may fail to meet its fourth carbon budget (CB4: 2023–2027) by as much as 146 Mt CO_2e (BEIS, 2017a; DECC, 2014a, 2015a). The DECC projections indicate a 7.5% overshoot in CB4, with an uncertainty range of 6–13%. This projected overshoot (DECC, 2015a) increases into the fifth carbon budget (CB5: 2028–2032), which the UK is at risk of exceeding by more than 14% (BEIS, 2017a).

Major Power Producers (MPPs), companies whose primary activity is electricity generation (DECC, 2012), produce 94% of all electricity in the UK. In 2015 over half of this production was from the combustion of coal (120 Terawatt Hours - TWh) and natural gas (71 TWh) (DECC, 2015b). GHG emissions from MPPs are traded within the European Union Emissions Trading Scheme (EU ETS), and are capped by UK emissions allowances granted by EU ETS. These emissions do not affect the UK's ability to meet carbon budgets directly, however, the continued use of fossil fuels by MPPs maintains a domestic demand for fossil fuels, which can create emissions in other non-traded sectors of the economy (e.g. coal and gas extraction). UK electricity production is projected to shift away from coal generation towards gas power, to supplement growing renewables and nuclear capacity (BEIS, 2016a, 2017a; European Parliament and the Council on Industrial Emissions, 2010; UK House of Commons, 2013). Yet, domestic production of natural gas will continue to fall (OGA, 2016). If the UK shifts the source of this gas from domestic North Sea gas to imported liquid natural gas (LNG), associated UK gas production emissions will fall while production-phase emissions elsewhere in the globe would increase. Conversely, a domestic shale gas industry could provide increased energy security for the UK, but would create a new source of domestic industrial emissions that is not yet fully accounted for within planned UK carbon budgets.

The CCC has stated that a UK shale gas industry is not compatible with UK climate change targets unless three test criteria are met: (1) production emissions are strictly limited; (2) UK gas consumption declines, remains in line with carbon budgets, and displaces imports; (3) production emissions are offset elsewhere in UK carbon budgets (CCC, 2016a, 2016b). The first test can be met by strict regulation of practices associated with shale gas production, many of which are agreed upon by industry (UKOOG, 2015). The second test may be met by maintaining or lowering UK gas consumption, while measuring and prioritizing the lowest carbon footprint gas to be consumed in the UK. The third test will require national coordination of sectoral GHG emissions to accommodate any additional emissions associated with domestic shale gas production.

In addition to the shale gas criteria, the CCC recommended a grid electricity emissions target of 50 g CO_2e kWh^{-1} by 2030 in the fourth carbon budget report (CCC, 2010), but have since relaxed that goal to below 100 g CO_2e kWh^{-1} by 2030 (CCC, 2015). The CCC projects this goal will be met by a combination of renewables, natural gas, carbon capture and storage (CCS), and nuclear power. DECC/BEIS has projected several scenarios which illustrate pathways to a 100 g CO_2e kWh^{-1} target by 2030. This study aims to quantify the emissions associated with gas consumption in the UK for electricity generation under scenarios projected by DECC/BEIS, and identify 'CCC-test' limits on emissions for a domestic shale gas industry.

1.1. DECC & BEIS projections

DECC/BEIS produce annual projections for *Updated energy and emissions scenarios* (BEIS, 2017a; DECC, 2014a, 2015a) which incorporate GHG-reduction policies, fossil fuel prices, and economic growth projections. The *Reference Scenario* is based on central estimates of economic growth and fossil fuel prices - it is therefore treated as the central estimate in this study. It contains all agreed-upon policies and planned policies. DECC's *Low Growth*, *High Growth*, *Low Prices*, and *High Prices* projections assume the same policies as the *Reference Scenario* but incorporate variance on fossil fuel prices and economic growth. Their *Existing Policies* projection contains central estimates, but excludes planned policies; it is an assessment of the current state of policies projected forward. Finally, the DECC *Baseline Policies* projection contains only policies that existed before the Low Carbon Transition Plan of 2009 (Great Britain and HM Government, 2009), and is therefore excluded from this analysis.

1.2. Gas demand & production

In 2016, UK gas demand was 67.0–72.0 billion cubic meters (bcm) (BEIS, 2017b; OGA, 2017), which was supplied by domestic and imported sources. Total domestic production, before exports, was 37.0 bcm. Imported gas (30.9 bcm) came from Norway, Belgium, and The Netherlands via interconnections. An additional (13.9 bcm) of liquefied natural gas (LNG) was supplied from Qatar (12.9 bcm), Algeria (0.5 bcm), Trinidad & Tobago (0.5 bcm), with negligible amounts from Nigeria (44 mcm), and Norway (55 mcm). Exports through interconnection were 14.2 bcm with an additional 276 mcm exported as LNG. After subtracting exported gas, UK used around 27% of gas in electricity generation or 19.2 bcm. Of this, 16.9 bcm were used by MPPs, the remaining gas being used in autogenerators (BEIS, 2016a, 2016b; OGA, 2017).

The Oil and Gas Authority (OGA) forecasts that domestic oil and gas production will decline by 5% yr^{-1} from 2022 until 2035, with gas production dropping from 34.7 bcm in 2018 to 14.5 bcm in 2035. Demand across all UK sectors is projected to decline more slowly - from 74.1 bcm in 2018 to 61.5 bcm in 2035 - despite impetus from carbon budgets and further growth in renewable energy supply. Without a shale gas industry, falling domestic production could increase the UK's domestic supply gap to more than 796 bcm (OGA, 2017) (see Fig. 1). This would require imports to increase from 53% of demand in 2018 to an estimated 76% of demand in 2035.

1.2.1. UK shale gas resource estimates

The potential of the UK shale gas resource to fill the projected domestic gas supply gap is an area of substantial policy and commercial interest (Bradshaw et al., 2014). Advanced Resources International (ARI) estimate that the UK holds 3783 bcm (133.4 trillion cubic feet, tcf) of 'risked gas-in-place' – gas which may be accessed given geological knowledge and production history - from a larger 17,641 bcm (623 tcf) of total shale gas. Of the risked gas-in-place, 728 bcm (25.7 tcf) is estimated to be technically recoverable (Kuuskraa et al., 2013). This corresponds to a 19.2% recovery rate of technically recoverable resources, similar to the mean estimates of around 20% used by Kuuskraa et al. (2011, 2013).

The British Geological Survey (BGS) estimate that the UK has a total of 39,900 bcm of shale gas, with a range of 24,700–68,400 bcm

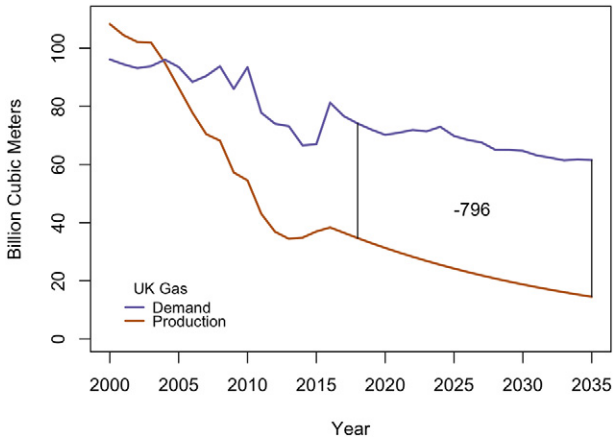

Fig. 1. UK natural gas production and demand for all sectors projected to 2035. Declining domestic production will create an import demand of 796 billion cubic meters from 2018 to 2035. Figure generated from OGA projections (OGA, 2017).

(Andrews, 2013; Monaghan, 2014). Though considerably more than the ARI estimate, BGS surveyed three basins (Carboniferous Midland Valley, Carboniferous Bowland-Hodder, Jurassic Weald) while the ARI estimate covers all Carboniferous shale basins grouped together along with the Jurassic Weald basin. It is likely that these estimates will be further refined as Cuadrilla begins shale gas exploration in Lancashire (Cuadrilla Resources, 2016).

BGS do not provide estimates of 'risked gas-in-place', or technically recoverable resources. If it is assumed that the ARI ratio of risked gas-in-place to total resource estimate of 21.4% is also applicable to the BGS resource estimates, the range of risked gas-in-place across the three BGS-surveyed basins is 5297–14,668 bcm. Based on industry experiences in Poland, applying a conservative economic recovery rate of 10% (Inman, 2016; Kuuskraa et al., 2013) to these low-end 'risked gas-in-place' estimates (ARI and BGS-derived) therefore corresponds to 378–530 bcm of economically recoverable domestic shale gas. This compares to the UK's projected 796 bcm gas supply gap over the next two decades.

2. Methods

This study examines two specific GHG emission scopes: 'grid emissions from natural gas power' and 'associated gas production emissions'. Here, 'grid emissions' are defined as the direct GHG emissions arising from combustion of fossil fuels for electricity generation divided by total electricity delivered. These GHG emissions are traded within the EU ETS, and count towards the grid emissions goal of 100 g CO_2e kWh^{-1} by 2030. 'Associated gas production GHG emissions' here include power plant construction, fuel extraction and processing, and fuel transportation.

When 'associated gas production emissions' occur within the UK, they are counted towards non-traded carbon budgets. 'Associated gas production emissions' occurring outside the UK do not affect carbon budgets, and would represent a saving to the UK carbon budgets, but break CCC's third test criteria (CCC, 2016a, 2016b). These emissions are also counted in a 'non-UK' category.

The sum of 'grid emissions' and all 'associated gas production emissions' provides a fuller assessment of the GHG impact of each fuel source used for UK electricity supply. We use GHG footprint estimates (Stamford and Azapagic, 2014) to calculate the impact of DECC/BEIS projections of future gas electricity against CCC's test criteria for UK shale gas exploitation and the grid emissions goal (100 g CO_2e kWh^{-1} by 2030). We also categorize 'associated gas production emissions' by UK carbon budget period for those occurring within the UK. 'Associated gas production emissions' occurring outside the UK are also tallied based on origin of gas supply within each model (see Section 2.2 below).

2.1. Gas supply from NTS

Here we assume that all gas demand for electricity generation in the UK is supplied via the UK National Transmission System (NTS). Natural gas for combustion at each power plant is assumed to come from the NTS, combustion phase emissions are therefore assumed to be equal. When gas arrives in the UK via interconnection or LNG terminal, it enters the NTS making the geographic origin unknown to the end user. Gas flows between the UK and continental Europe are excluded from the calculations because they account for less than 1% of total consumption, fluctuate rapidly with market demand, and lack GHG footprint figures because of the unquantified sources of European continental gas (BEIS, 2017a; Stamford and Azapagic, 2014). In the absence of nation-specific data, LNG from Nigeria and Trinidad & Tobago are here assumed to have the same production phase emissions as LNG from Algeria. The imports from each of these countries represent less than 1% of gas supply, but are reported in annual UK gas supply figures (BEIS, 2016b). Finally, imported North Sea gas is assumed to have the same production phase emissions as UK domestic gas.

We use the projected gas demand from DECC/BEIS, and OGA (BEIS, 2017a; OGA, 2017). Dependency on imports is assumed equal to OGA estimates of domestic demand minus domestic production. There are statistical differences between the net sum of all imports minus exports, and the import dependency. This is due to the constraints of monthly, quarterly, and annual measurements and reporting. We assume that the net import/exports are zero over the life of the calculations, and are rounded to zero by adjustments in pipeline imports. We assume zero bunkering of gas.

Upstream gas extraction emissions count towards the UK carbon budget, when occurring within the UK. Emissions from the transportation of fuel (natural gas) are reported in the *Mobile Combustion Process* category within the energy sector (IPCC, 2000), are pre-combustion, and so are not counted towards grid emissions. These emissions are counted under 'associated gas production emissions'. Furthermore, shipping of natural gas products as liquid natural gas (LNG) contains transportation emissions which are tallied in the carbon budget of the ship's home country.

The emissions intensity of imported gas represents the current estimates of global supply. Further expansion of fracking in nations from which gas is imported to the UK could further increase overseas emissions while leaving reported emission in the UK unaffected. To determine the potential impact of a shale gas industry versus increased gas imports on UK carbon budgets, we model four gas supply scenarios:

2.1.1. Scenario 1 – current gas supply projected forward

Here total UK gas demand fluctuates according to DECC/BEIS and OGA estimates from 2018 to 2035, while UK production declines −5% yr^{-1} from 2022 onwards (OGA, 2017). The 2016 global supply sources of natural gas to the UK (BEIS, 2017b) are assumed to remain the same through to 2035. The growing UK gas supply gap is assumed to be met by Norwegian North Sea imports, Qatari LNG, and other LNG imports. These three gas sources increase proportionately from 2016 onwards to meet projected demand, with a presumption that shale gas is not produced in the UK. This scenario represents our baseline emissions scenario.

2.1.2. Scenario 2 – increased gas from Norway

Here total UK production falls as projected by OGA estimates, as in scenario 1. As UK gas declines in production from 2022 onwards, North Sea gas supply from Norway increases to meet UK demand. Qatari LNG and other LNG imports continue in the same quantity as 2016 (10.1 bcm, and 0.91 bcm respectively). Again, this scenario assumes that shale gas is not produced in the UK. This scenario demonstrates shifting of associated gas production emissions from the UK to Norway.

2.1.3. Scenario 3 – increased LNGs from Qatar

Here UK gas demand fluctuates as in scenarios 1 & 2, UK gas production again declines as projected by OGA estimates. North Sea gas from Norway, and other LNG imports, continue to be imported in the same quantity as 2016 (19.6 bcm and 0.91 bcm respectively) and shale gas is not produced in the UK. Instead, Qatari LNG imports increase to meet the growing supply gap. This scenario demonstrates of shifting responsibility of associated gas production emissions from the UK, and places more emphasis on LNG from Qatar.

2.1.4. Scenario 4 – shale gas from UK

In this final scenario, UK gas demand fluctuates as in scenarios 1, 2, & 3, UK gas production declines falls as projected by OGA estimates. Imports from Norway, Qatar and other LNG are imported in the same quantities as in 2016 (19.6 bcm, 10.1 bcm, and 0.91 bcm respectively.) Here, UK shale gas production is assumed to expand to meet the supply gap starting in 2018 with 8.9 bcm production. Shale gas reaches 27% of supply by 2035 with 16.4 bcm produced, totalling 246 bcm over the model period. This scenario illustrates the potential impact of UK shale

gas exploitation on carbon budget periods due to increased domestic 'associated gas production' emissions.

2.2. Electricity source emissions and capacity

As discussed above, within the GHG footprint of electricity generation are combustion emissions and GHG emissions associated with power plant construction, fuel extraction, materials manufacturing, and decommissioning (Stamford and Azapagic, 2014). Combustion emissions divided by electricity delivery are counted towards the grid decarbonisation goal of 100 g CO_2e kWh^{-1}. Other 'associated emissions' count as non-traded industrial emissions and affect carbon budgets (CCC, 2016a, 2016b; IPCC, 2000). For the following electricity fuel sources, we multiply the 'combustion emissions' by the DECC/BEIS projections for delivered electricity to measure the progress towards the grid emissions goal of 100 g CO_2e kWh^{-1}. 'Associated emissions' are emissions associated with the production and supply of gas that is then used in UK power generation.

2.2.1. Fossil electricity sources

Future GHG emissions from oil combustion are not considered in our analysis as oil has been phased out as a major gird electricity source in the UK since 2013, and generated just 0.60 TWh in 2015 (BEIS, 2017a). When incorporating past emissions, electricity from oil is assumed to have a 'combustion emissions' intensity of 750 g CO_2e kWh^{-1} (Weisser, 2007).

We here assume that coal power in the UK will be phased out in the next decade (European Parliament and the Council on Industrial Emissions, 2010), but will play some role in UK power until 2026 particularly in the BEIS *High Prices Scenario* (BEIS, 2017a). We assume that coal has 'combustion emissions' factor of 941 g CO_2e kWh^{-1} (Stamford and Azapagic, 2014).

By 2035, it is projected that 25.6 GW of new gas capacity will have been built by MPPs. The total capacity will be 34.2 GW in 2035. Natural gas is expected to deliver 20.2–38.3 TWh in 2035, with 27.9 TWh as the central estimate. We assume that natural gas power in the UK has a 'combustion emissions' of 386 g CO_2e kWh^{-1} based on Stamford and Azapagic (2014). This is in agreement with the range of 365–415 g CO_2e kWh^{-1} annually reported by BEIS/DECC (BEIS, 2016a; DECC, 2012, 2013, 2014b, 2015b). Likewise, we assume GHG intensity figures from Stamford and Azapagic (2014) of 401–508 g CO_2e kWh^{-1}, including the shale gas central estimate of 462 g CO_2e kWh^{-1} (see Table 1). Variance in geographic gas supply changes the GHG intensity figures for gas in each of the four fuel mix scenarios as described above.

2.2.2. Low GHG electricity sources

We assume 16.0 GW of new nuclear capacity by 2035, part of a projected 17.2 GW of total nuclear capacity producing 135 TWh or 38% of UK demand by 2035 based on BEIS (2017a) projections. We assume the 'combustion emissions' for nuclear power are zero (Sovacool, 2008).

Table 1
GHG phase emissions of UK natural gas combined cycle power from Stamford and Azapagic (2014). All combustion emissions count towards the gird emissions target of 100 g CO_2e kWh^{-1}. The remaining 'associated emissions,' including plant construction, extraction and processing, and fuel transportation count UK carbon budgets when occurring within the UK.

Phase emissions (g CO_2e kWh^{-1})	UK North Sea gas	Norwegian North Sea gas	LNG Algeria	LNG Qatar	UK shale gas (central)
Plant construction	0.958	0.958	0.958	0.958	0.958
Extraction and processing	2.8	2.8	15.8	2.8	65.9
Fuel transport	10.8	10.8	82.2	118.0	8.9
Combustion	386.3	386.3	386.3	386.3	386.3
Total	400.8	400.8	485.3	508.1	462.0

The installed UK renewable energy capacity projected by BEIS/DECC does not specify what percentage will be solar, wind, hydro, or biomass. To simplify, we here assume that 174–177 TWh of renewable electricity will be generated from 63 GW of wind and solar capacity in 2035 based on BEIS (2017a) projections. Previously, DECC (2015a) projected 152 TWh with a range of 142.8–159.0 TWh in the central scenarios. In 2016, solar and wind generated 57.8% of renewable electricity (12.4% and 45.3% respectively) up from 37% in 2009 (BEIS, 2017c). We assume the 'combustion emissions' for these renewables are zero (Nugent and Sovacool, 2014). Biomass contributed 22% of renewable electricity in 2016 (BEIS, 2017c). However, there is very high variability in LCA estimates for biomass energy GHG intensity, including potentially negative emissions (Stephenson and MacKay, 2014). We have therefore excluded biomass energy generation estimates from our scenarios and instead assume all UK renewable electricity is represented by an even split between solar and wind power.

2.3. Electricity generation GHG emissions

To examine the impact of a potential UK shale gas supply versus increased gas imports on the UK electricity intensity target of 100 g CO_2e kWh^{-1} (and UK carbon budgets), the BEIS/DECC projections (see Section 1.1) models were evaluated and annual grid intensity calculated. Our assessment does not include microgeneration, systems with less than 50 kilowatt electricity generation capacity (UK Parliament, 2004), and instead focuses on major power producers from five main generation types (Renewables, Coal, Oil, Natural Gas, and Nuclear).

BEIS/DECC projects 7 versions of electricity emissions through to 2035, their *Reference Scenario* is here treated as our central estimate. We multiplied the projected electricity generation type (TWh) by the corresponding 'combustion emissions'. The annual sums of the electricity generation emissions are divided by the total electricity delivered in each model for that year. This gives the grid factor for each of the 4 fuel mix scenarios from the range of generation projected by BEIS/DECC through 2035.

We separated the associated non-combustion emissions for natural gas power from the combustion emissions. These emissions are categorized into carbon budget periods for UK emissions and non-UK emissions, to show the additional impact of domestic shale gas (scenario 4) on carbon budgets.

3. Results and discussion

3.1. Gas combustion emissions

In our calculations, variance in grid emissions, and progress towards 100 g CO_2e kWh^{-1}, is driven by the DECC/BEIS projections (BEIS, 2017a; DECC, 2014a, 2015a) for total gas-derived electricity. The geographic origin of the gas inputs to the NTS affects only the non-combustion associated emissions. For all 4 UK gas supply scenarios examined here, we assume equal gas 'combustion emissions' (Stamford and Azapagic, 2014).

For the central BEIS projections, using the Stamford and Azapagic (2014) estimates of natural gas combustion intensity, 420–466 Mt CO_2e (460) will be emitted from natural gas power in the UK from 2018 to 2035, compared to 280–397 Mt CO_2e (397) in the 2015 projections (see Fig. 2). The narrow range in the 2016 projections is due to increased proportions of renewables in the 2016 projections by BEIS (2017a). Natural gas for electricity generation is expected to be increasingly substituted by renewable power, yet will still be responsible for more than 460 Mt CO_2e over the next 2 decades from combustion alone. These emissions will require permits for trading through the EU ETS during carbon budget periods 3–6.

The use of UK shale gas does not affect the combustion emissions, as they are a function of electricity demand and total gas usage.

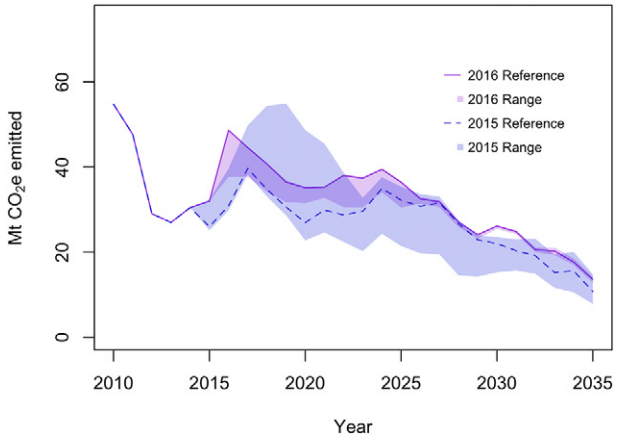

Fig. 2. CO_2e emissions from natural gas combustion for electricity supply in 2015 & 2016 BEIS/DECC projections (BEIS, 2017a; DECC, 2015a). Despite increased renewable capacity, the UK is projected to be reliant on natural gas power for electricity supply in all BEIS/DECC projections. We assume combustion of gas is 386 g CO_2e kWh^{-1} (Stamford and Azapagic, 2014), and when multiplied by 2016 BEIS/DECC projections, the UK will emit 420–466 Mt CO_2e from 2018 to 2035 from natural gas electricity generation.

Multiplying the DECC/BEIS projections (BEIS, 2017a; DECC, 2014a, 2015a) by grid intensities for electricity type suggests that the 100 g CO_2e kWh^{-1} goal will be reached by 2028 in the *Reference Scenario* for both 2015 and 2016 projections. However, this goal could be jeopardized by lack of progress on establishing more ambitious UK GHG reduction policy, illustrated by the *Existing Policies Scenario*. In this scenario, the grid intensity goal is not reached by 2035 (see Fig. 3).

3.2. Associated gas production emissions

The associated gas production emissions are separated by carbon budget periods (CB3–CB6) for UK emissions. Non-UK emissions are those from fuel production and transportation outside of the UK. In scenarios 1, 2, & 3, UK emissions are similar across all carbon budget periods (see Fig. 4). In scenario 4 (domestic shale gas), the UK would emit 28.5 Mt CO_2e (25.8–28.8 range) from 2018 to 2035 (as reported under current guidelines from The United Nations Framework Convention on Climate Change - UNFCCC) with an additional 32.0 Mt CO_2e (29.0–32.4 range) being emitted outside of the UK. If UK shale gas was not produced and the UK relied more on Qatari LNG (scenario 3), the share of UK-associated emissions (as reported under UNFCCC guidelines) would reduce to 8.1 Mt CO_2e (7.2–8.1), but overall emissions to the atmosphere would actually increase to 64.9 Mt CO_2e (59.0–65.8), an 11.5 Mt CO_2e increase over scenario 4. These sums indicate that the shale scenario (4) globally saves 12.5 Mt CO_2e over the Qatari LNG scenario (3), but shifts emissions to the UK in terms of reporting requirements. Scenario 4, globally, leads to higher emissions than scenarios 1 & 2 (24.4 Mt CO_2e higher), and increases UK-reported emissions by 20.4 Mt CO_2e during carbon budget periods 3–6. This 20.4 Mt CO_2e of production-phase emissions is in addition to the 460 Mt CO_2e emitted due to combustion at UK gas power plants over the same period (see Fig. 2).

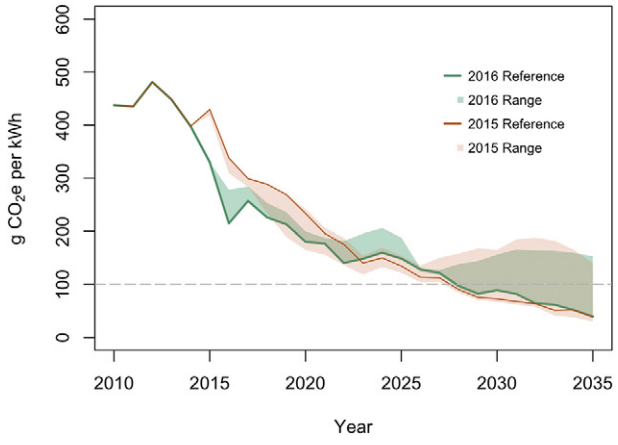

Fig. 3. Projections of progress towards UK grid intensity target of 100 g CO_2e kWh^{-1}. Current DECC/BEIS projections (BEIS, 2017a; DECC, 2015a) indicate the grid intensity target will be reached by 2028 in the Reference Scenario. However, the target may be in jeopardy if no new climate policies are enacted. The top of the range for 2015 & 2016 indicate that without further progress on climate legislation, the grid emissions target will not be met.

3.3. Fugitive CH_4 emissions in shale gas production

A key assumption in the Stamford and Azapagic (2014) data is a low fugitive emissions rate in the central case during shale gas production. Stamford and Azapagic (2014) do not calculate fugitive emission percentages, rather state fugitive emissions as a set volume per meter drilled based on EPA and Ecoinvent figures (Ecoinvent Centre, 2010; US EPA National Center for Environmental, 2012). These values are 0 m^3 gas, 4.1 m^3 gas, and 54 m^3 gas per meter drilled for the best, central, and worse cases respectively. Assuming the well is 5773 m (vertical 2773 m, horizontal 3000 m), 0 m^3 gas, 23,669 m^3 gas, and 312,000 m^3 gas leaks in each respective case. Dividing these figures by the *estimated ultimate recovery per well* (EUR) of 84.95 Mm^3 (3 bcf), 28.32 Mm^3 (1 bcf), and 2.832 Mm^3 (0.1 bcf) respectively, suggests fugitive emissions rates of 0%, 0.08%, and 11.0% during well completion.

The composition of recovered gas is different in each case, shifting from sweet in the best case to sour in the worst case. The methane content of the gas in the best-case scenario contains 0.61 kg CH_4 m^{-3} compared to 0.555 kg CH_4 m^{-3} and 0.5 kg CH_4 m^{-3} in the central and worst cases respectively. The gas also contains 0.13 kg CO_2 m^{-3}, 0.115 kg CO_2 m^{-3}, and 0.1 kg CO_2 m^{-3} respectively. Assuming that 1 t CH_4 = 25 t CO_2e, each case leaks 0 t CO_2e, 331 t CO_2e, and 3931 t CO_2e per well drilled during well completion.

Emissions from flaring and intentional venting are set as a function of gas recovered, therefore the worst-case scenario has the least amount of flared and intentionally vented gas. Stamford and Azapagic (2014) assume venting and flaring of 11.2 g CO_2 m^{-3} and 0.264 g CH_4 m^{-3} gas produced. We assume the remaining CH_4 is vented and not flared. Assuming that 1 t CH_4 = 25 t CO_2e, 1529 t CO_2e per well is vented and flared in the best case compared with 510 t CO_2e and 50.9 t CO_2e in the central and worst cases respectively. Considering all emissions in Stamford and Azapagic (2014), the shale gas scenarios represent increases of 2.8% (best-case), 15.3% (central-case), and 175% (worst-case) over the same quantity of UK North Sea gas.

Westaway et al. (2015) criticize the high leakage used by Stamford and Azapagic (2014) in their worst-case scenario. They claim this is unlikely due to more strict UK oil and gas regulations, and the low EUR would make the well uneconomical. Stamford and Azapagic (2015) agreed with these assessments, but included this high estimate to illustrate the worst-case inferred in the USA by the literature at the time (Howarth et al., 2011). Howarth et al. (2011) conclude that 2–3% fugitive emissions rate would be the break-even point for conventional gas to be equal with coal in electricity generation GHG emissions. Experience in the US has shown fugitive emission rates as high as 12% in some cases (Howarth, 2015) with both systemic and accidental one-off events. These events are difficult to detect, measure, and quantify. Shale gas production practices and regulations will be more strict in the UK than the US (UKOOG, 2015).

We calculate the impact of 3% fugitive emissions during well completion based on the Stamford and Azapagic (2014) central case. We assume that the EUR (28.32 Mm^3) and gas composition

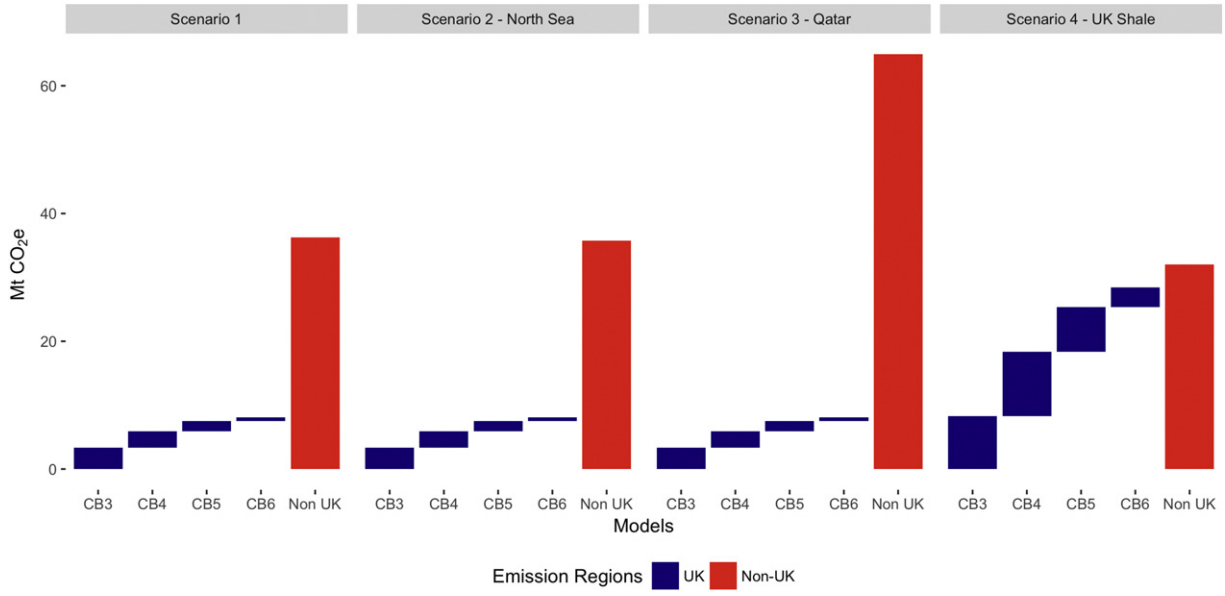

Fig. 4. Associated natural gas power production emissions by carbon budget period for 4 models in the central 2016 BEIS projection (BEIS, 2017a). Non-UK and total emissions are highest when using Qatari LNG. UK emissions are highest in scenario 4, when exploiting a domestic shale gas resource. The UK would be responsible for 28.5. These sums indicate that the shale scenario (4) globally saves 12.5 Mt CO_2e over the Qatari LNG scenario (3), but shifts emissions to the UK. Scenario 4 is globally worse than the scenarios 1 & 2 by 24.4 Mt CO_2e, and increases UK emissions by 20.4 Mt CO_2e during carbon budget periods 3–6.

(0.555 kg CH_4 m^{-3} & 0.115 kg CO_2 m^{-3}) are the same, but the leakage rate is increased from 0.08% to 3%. This increases fugitive emissions during well completion from 331 t CO_2e to 11,886 t CO_2e while the planned venting and flaring is the same (510 t CO_2e). Repeating this process for 1% (EPA, 2014, 2017) and 2% (Howarth et al., 2011) leakage rates during well completion gives 4472 t CO_2e and 8434 t CO_2e leaked respectively. An additional 510 t CO_2e is emitted from flaring and venting. These changes in the leakage rates correspond to increases in the production phase emissions for the central case (Stamford and Azapagic, 2014) from 65.8 g CO_2e kWh^{-1} to 265 g CO_2e kWh^{-1}, 500 g CO_2e kWh^{-1}, and 735 g CO_2e kWh^{-1} in each case. This does not consider emissions for site preparation, or on-site diesel generators which are not quantified in Stamford and Azapagic (2014).

We adjust the fugitive emissions rate to 1%, 2% & 3%, and repeat the process for calculating scenario 4, to illustrate the increase in UK associated gas production emissions (see Figs. 5 & 6). When the fugitive emissions rate is increased to 1%, an additional 54.2 Mt CO_2e (49.5–55.0 Mt CO_2e range) are emitted during carbon budget periods 3–6. When the rate is increased to 3%, an additional 182.3 Mt CO_2e (166.0–184.7 Mt CO_2e range) are emitted compared to the low (0.08%) leakage rate in scenario 4. Comparing scenario 4 (UK shale gas) with 1% leakage rate to scenario 3 (increased Qatari LNG), an additional 74.6 Mt CO_2e are emitted in the UK carbon budget periods (68.8–75.6 Mt CO_2e range). This same adjustment increases global emissions by 41.7 Mt CO_2e (35.1–42.7 Mt CO_2e range) over the same period. This indicates that even a modest increase in fugitive emissions makes shale gas worse for carbon budgets, and global emissions, compared with increases in LNG imports to the UK.

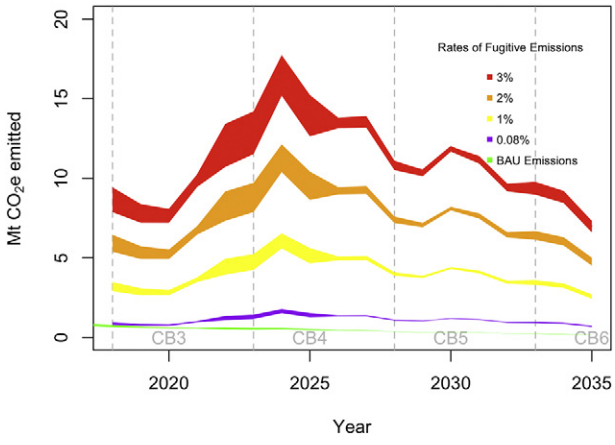

Fig. 5. Variance in greenhouse gas emissions from fugitive emissions, vented, and flared gas in the UK applied to scenario 4. Stamford and Azapagic (2014) assume a 0.08% leakage rate during well completion, which contribute to a small source of upstream shale gas emissions. Here we model leakage rates of 1%, 2%, and 3% compared with Stamford and Azapagic, and business-as-usual (BAU) UK gas production emissions from DECC/BEIS (BEIS, 2017a). Variance in DECC/BEIS estimates of UK gas-derived electricity creates the range of each estimate. These emissions would need to be accommodated into UK carbon budget periods 3–6.

4. Policy implications and further research

4.1. Impact on carbon targets & budgets

Under the current reporting regime (IPCC et al., 2006), the source of natural gas has no bearing on the UK's ability to reach the grid intensity target. The amount of projected natural gas in the electricity system, compared with lower GHG electricity sources, is the main factor in determining the grid intensity results. In response to UK Government funding cuts for carbon capture and storage (CCS), BEIS has all but eliminated CCS deployment from future projections, and increased the dependency on fossil fuel electricity to supplement the intermittency of renewables (BEIS, 2017a). This places more pressure on gas imports, or a domestic shale gas industry to meet the gas power supply gap. Imported gas would have a lower impact on UK carbon budgets under current reporting requirements, but UK shale gas may have lower overall emissions than imported LNG if shale gas production emissions were very low. However, domestic shale gas production with even a modest 1% fugitive emissions rate would risk exceedance of UK carbon budgets.

Regardless of these projections, this study indicates that the UK grid intensity target can be achieved in the second half of next decade in the BEIS *Reference Scenario* and *High Fuel Price Scenario* (BEIS, 2017a). If UK shale gas production were to go forward in 2018 (scenario 4), the UK would be responsible for all emissions industry-wide within carbon

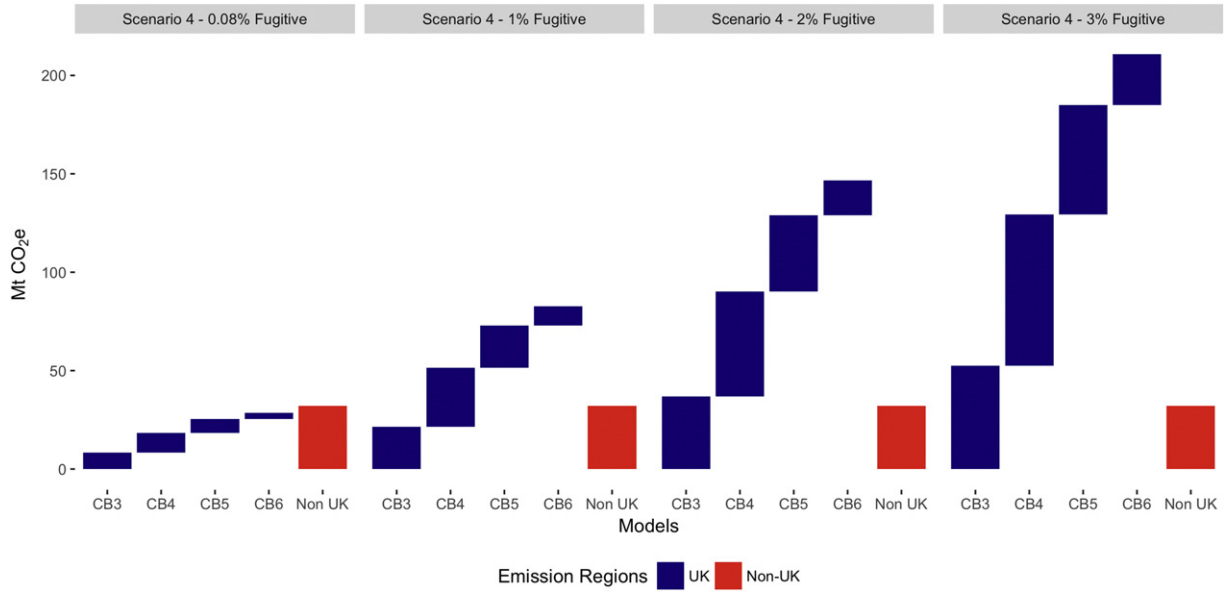

Fig. 6. Associated gas production emissions for natural gas power by carbon budget period for 4 models in the central 2016 BEIS projection (BEIS, 2017a), adjusted for higher fugitive shale gas emissions. Stamford and Azapagic (2014) assume 0.08% fugitive leakage in the UK. We increase the leakage rate to 1%, 2%, and 3%, and find that up to 210 Mt CO_2e are emitted in gas production for natural gas power if leakage rates increase to equal observations in the US.

budgets under the current reporting regime. The BEIS (2017a) projections do not incorporate UK shale gas production estimates into their projections, however, using the BEIS *Existing Policies Scenario* gives the high estimates for grid intensity of gas electricity. Based on the current GHG accounting practices (see 4.2 below), current climate policies, and globalized market for LNG, the UK would likely use the lowest-priced gas regardless of origin. Without further progress on UK climate policies, cheaper LNG imports would place the grid intensity goal in jeopardy (see Fig. 3).

4.2. Production & consumption-based accounting practices

This study illustrates potential gaps and unintended consequences in production-based GHG accounting practices. While production-based accounting is in line the UNFCCC reporting (IPCC et al., 2006), it allows for potential 'offshoring' of GHG emissions in the international trade of fossil fuels. As the four scenarios encompass a range of domestic and imported gas supplies, a scenario of increased imports could increase the emissions burden for the source nations. Even the highest import scenario considered here, the amount of gas imported to the UK from these nations is a small percentage of their total exports. The UK's commitment to national carbon budgets based on production emission may create a perverse incentive to pursue fossil fuel imports and increase industrial emissions overseas that do not then appear in UK GHG accounts. Essentially, the UK would export responsibility of emissions to meet carbon budgets. Under these reporting systems, a domestic shale gas industry would bring some production emissions back within the UK budgets. As shown above, 20.1 Mt CO_2e in total would be emitted in our model with a low fugitive emissions rate (0.08%). These emissions would be acceptable in terms of net climate impact if they are less than the same quantity of emissions per unit of electricity from imported Qatari LNG. And, most importantly, the same quantity of LNG is not produced.

Under a consumption-based emissions accounting system, such offshoring of emissions might be avoided. For the UK to maintain a leadership position on GHG reduction policies, we suggest that incentivization of use of the lowest GHG-intensity natural gas for power generation could be encouraged through such consumption based accounting.

4.3. Peaking gas power & renewable support

Stamford and Azapagic (2014) assumed 52.5% load factor for natural gas plants in their calculations. We do not adjust for lower load factors (power generation divided by capacity) in the future scenarios. BEIS data (BEIS, 2017a) project a gas power load factor below 30% in 2028 and beyond. Gas plants are more efficient when used for baseload power. If the UK commits to natural gas power for renewable support, higher load factors would be advantageous. A gas plant used at baseload power would emit more CO_2e per plant, but fewer plants would need to be built, and gas demand could be reduced and planned. This paradox between gas capacity and renewable support disagrees with the motivation for 100% renewable power, but would save construction costs and GHGs. This also assumes that storage and interconnection will not be able to provide 100% backup for renewable electricity.

If the UK imports power from continental Europe, there is an issue of GHG-intensity of this imported power. The 2016 *Updated Energy and Emissions Projections* (BEIS, 2017a) included storage in their calculations for electricity delivery the first time. The report also increased the supply of electricity from interconnection. These figures are outside of the boundaries of this study, but indicate a projected reliance on the EU continental grid for electricity supply.

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Glossary

ARI: Advanced Resources International
BAU: business-as-usual
bcm: billion cubic meter
BEIS: Department for Business, Energy, and Industrial Strategy
BGS: British Geological Survey
CCC: Committee on Climate Change
CCS: carbon capture and storage
CO_2e: carbon dioxide equivalent
DECC: Department for Energy and Climate Change
EU ETS: European Union Emissions Trading Scheme
EUR: estimated ultimate recovery per well
EPA: Environmental Protection Agency
g CO_2e: gram carbon dioxide equivalent
GHG: greenhouse gas
GW: gigawatt
kWh: kilowatt hour
LCA: lifecycle assessment
LNG: liquefied natural gas
MPP: Major Power Producers
Mt CO_2e: megatonne carbon dioxide equivalent
NTS: UK National Transmissions System
OGA: Oil and Gas Authority
t CO_2e: tonne carbon dioxide equivalent
tcf: trillion cubic feet
TWh: terawatt hour
UNFCCC: United Nations Framework Convention on Climate Change